2 Modeling Framework

ICF Consulting developed the Integrated Planning Model (IPM) to support analysis of the electric sector. EPA, state air regulatory agencies, utilities and other public and private sector clients have used IPM extensively for air regulatory analyses, market studies, strategy planning, due diligence, and economic impact assessments.

This chapter begins with a brief overview of the purpose, capabilities and applications of IPM. This is followed by sections devoted to model structure and formulation, key methodological characteristics of IPM, and IPM's programming features, including its handling of model inputs and outputs. Readers may find some overlap between sections. For example, transmission decision variables and constraints are covered in section 2.2's discussion of model structure and formulation, and transmission modeling is covered as a key methodological feature in section 2.3.9. The different perspectives of each section are designed to provide readers with information that is complementary rather than repetitive.

2.1 IPM Overview

IPM is a well-established model of the electric power sector designed to help government and industry analyze a wide range of issues related to this sector. The model represents economic activities in key components of energy markets – fuel markets, emission markets, and electricity markets. Since the model captures the linkages in electricity markets, it is well suited for developing integrated analyses of the impacts of alternative regulatory policies on the power sector. In the past, applications of IPM have included capacity planning, environmental policy analysis and compliance planning, wholesale price forecasting, and asset valuation.

2.1.1 Purpose and Capabilities

IPM is a dynamic linear programming model that generates optimal decisions under perfect foresight. It determines the least-cost method of meeting energy and peak demand requirements over a specified period (e.g. 2005 to 2030). In its solution, the model considers a number of key operating or regulatory constraints (e.g. emission limits, transmission capabilities, renewable generation requirements, fuel market constraints) that are placed on the power and fuel markets. In particular, the model is well-suited to consider complex treatment of emission regulations involving trading, banking, and progressive flow control of emission allowances, as well as traditional command-and-control emission policies.

IPM models power markets through model regions that are geographical entities with distinct characteristics. For example, the model regions representing the U.S. power market in EPA Base Case 2000 correspond broadly to regions and sub-regions constituting the North American Electric Reliability Council (NERC) regions. IPM models the electric demand, generation, transmission, and distribution within each region as well as the inter-regional transmission grid. All existing utility power generation units, including renewable resources, are modeled, as well as independent power producers and cogeneration facilities that sell electricity to the grid.

IPM provides a detailed representation of new and existing resource options, including fossil generating options (coal steam, gas-fired simple cycle combustion turbines, combined cycles, and oil/gas steam), nuclear generating options, and renewable and non-conventional (e.g., fuel cells) resources. Renewable resource options include wind, geothermal, solar thermal, solar photovoltaic and biomass.

IPM can incorporate a detailed representation of fuel markets and can endogenously forecast fuel prices for coal, natural gas, and biomass by balancing fuel demand and supply for electric generation. The model also includes detailed fuel quality parameters to estimate emissions from electric generation.

IPM provides estimates of air emission changes, regional wholesale energy and capacity prices, incremental electric power system costs, changes in fuel use, and capacity and dispatch projections.

Applications

IPM's adaptability in assessing alternative planning strategies and regulatory policy options and flexibility in required level of data and analytic resources have made it suitable for a variety of applications. These include:

- **Air Regulatory Assessment:** Since IPM contains extensive air regulatory modeling features, state and federal air regulatory agencies have used the model extensively in support of air regulatory assessment.

- **Integrated Resource Planning:** IPM can be used to perform least-cost planning studies that simultaneously optimize demand-side options (load management and conservation), renewable options and traditional supply-side options.

- **Detailed Modeling of Dispatch:** IPM's dispatch algorithms have been benchmarked for accuracy against other dispatch models such as the production costing software PROMOD III, which is a widely accepted dispatching standard among electric-power generation planners.

- **Strategic Planning:** IPM can be used to assess the costs and risks associated with alternative utility and consumer resource planning strategies as characterized by the portfolio of options included in the input data base.

- **Options Assessment:** IPM allows industry and regulatory planners to "screen" alternative resource options and option combinations based upon their relative costs and contributions to meeting customer demands.

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- **Cost and Price Estimation:** IPM produces realistic estimates of energy prices, capacity prices, fuel prices, and allowance prices. Industry and regulatory agencies have used these cost reports for due diligence, planning, litigation and economic impact assessment.

2.2 Model Structure and Formulation

IPM employs a linear programming structure that is particularly well-suited for a dynamic electricity planning model designed to help decision makers plan system capacity and model the dispatch of electricity from individual units or plants. The model consists of three structural components: (1) a linear "objective function," (2) a series of "decision variables," and (3) a set of linear "constraints" over which the objective function is minimized to yield an optimal solution. The section below describes IPM's objective function, key decision variables, and constraints.

- **Objective Function:** IPM's objective function is the summation of all the costs incurred by the electricity sector over the entire planning horizon. The total resulting cost is expressed as the net present value of all the component costs. These costs, which the linear programming formulation attempts to minimize, include the cost of new plant and pollution control construction, fixed and variable operating and maintenance costs, and fuel costs. Many of these cost components are captured in the objective function by multiplying the decision variables, described below, by a cost coefficient. Cost escalation factors are used in the objective function to reflect changes in cost over time. The applicable discount rates are applied to derive the net present value for the entire planning horizon from the costs obtained for all years in the planning horizon.

Decision Variables

- **Generation Dispatch Decision Variables:** IPM includes decision variables representing the generation from each model power plant[1]. For each model plant, a separate generation decision variable is defined for each possible combination of fuel, season, model run year, and segment of the seasonal load duration curve applicable to the model plant. (See section 2.3.5 below for a discussion of load duration curves.) In the objective function, each plant's generation decision variable is multiplied by the relevant heat rate and fuel price (differentiated by the appropriate segment of the fuel supply curve) to obtain a fuel cost. It is also multiplied by the applicable variable operation and maintenance (VOM) cost rate to obtain the VOM cost for the plant.

- **Capacity Decision Variables:** IPM includes decision variables representing the capacity of each existing model plant and capacity additions associated with potential (new) units in each model run year. In the objective function, the decision variables representing existing capacity and capacity additions are multiplied by the relevant fixed operation and maintenance (FOM) cost rates to obtain the total FOM cost for a plant. The capacity addition decision variables are also multiplied by the investment cost and capital charge rates to obtain the capital cost associated with the capacity addition.

- **Transmission Decision Variables:** IPM includes decision variables representing the electricity transmission along each transmission link between model regions in each run year. In the objective function, these variables are multiplied by variable transmission cost rates to obtain the total cost of transmission across each link.

- **Emission Allowance Decision Variables:** For each relevant pollutant where allowance trading applies, IPM includes decision variables representing the total number of emission allowances for a given model run year that are bought and sold in that or subsequent run years. In the objective function, these year-differentiated allowance decision variables are multiplied by the market price for allowances prevailing in each run year. This formulation allows IPM to capture the inter-temporal trading and banking of allowances.

- **Fuel Decision Variables:** For each type of fuel and each model run year, IPM defines decision variables representing the quantity of fuel delivered from each fuel supply region to model plants in each demand region. Coal decision variables are further differentiated according to coal rank (bituminous, sub-bituminous, and lignite), sulfur grade (see section 8.1 and Table 8.5), and mercury content (see section 5.3.1 and 8.1 and Table 8.7). These fuel quality decision variables do not appear in the IPM objective function, but in constraints which define the types of fuel that each model plant is eligible to use and the supply regions that are eligible to provide fuel to each specific model plant.

Constraints

- **Reserve Margin Constraints:** These constraints capture system reliability requirements by defining a minimum margin of reserve capacity (in megawatts) per year for each region. If existing plus planned capacity is not enough to satisfy the reserve margin requirement, the model will add the required level of new resources.

- **Demand Constraints:** The model divides regional annual demand into seasonal load segments represented in a load duration curve (LDC). Each segment in the LDC defines the minimum amount of

[1]Model plants are aggregate representations of real life electric generating units. They are used by IPM to model the electric power sector. For a discussion of model plants in EPA Base Case 2000, see section 4.2.6.

generation required to meet the region's electrical demand during the specified season. These requirements are incorporated in the model's demand constraints.

- **Capacity Constraints:** These constraints specify how much electricity each plant can generate (a maximum generation level), given its capacity and seasonal availability.

- **Turn Down/Area Protection Constraints:** The model uses these constraints to take into account the cycling capabilities of the units, i.e., whether or not they can be shut down at night or on weekends, or whether they must operate at all times, at least at some minimum capacity level. These constraints ensure that the model reflects the distinct operating characteristics of peaking, cycling, and base load units.

- **Emissions Constraints:** IPM can consider an array of emissions constraints for SO_2, NO_x, mercury, and CO_2. Emission constraints can be implemented on a plant-by-plant, regional, or system-wide basis. The constraints can be defined in terms of a total tonnage cap (e.g., tons of SO_2) or a maximum emission rate (e.g., lb/mmBtu of NO_X). The scope, timing, and definition of the emission constraints depends on the required analysis.

- **Transmission Constraints:** IPM can simultaneously model any number of regions linked by transmission lines. The constraints define either a maximum capacity on each link, or a maximum level of transmission on two or more links (joint limits) to different regions.

- **Fuel Supply Constraints:** These constraints define the types of fuel that each model plant is eligible to use and the supply regions that are eligible to provide fuel to each specific model plant. A separate constraint is defined for each model plant.

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2.3 Key Methodological Features of IPM

IPM is a flexible modeling tool for obtaining short- and long-term projections of production activity in the electric generation sector. The projections obtained using IPM are not statements of what will happen but what might happen given the assumptions and methodologies used. Chapters 3 – 8 contain detailed discussions of the cost and performance assumptions specific to the EPA Base Case 2000. This section provides an overview of the essential methodological and structural features of IPM, that extend beyond the assumptions that are specific to EPA Base Case 2000.

2.3.1 Model Plants

Model plants are a central structural component that IPM uses in three ways: (1) to represent aggregations of existing generating units, (2) to represent retrofit, repowering, and retirement options that are available to existing units, and (3) to represent potential (new) units that the model can build.

Existing Units: Theoretically, there is no predefined limit on the number of units that can be included in IPM. However, to keep model size and solution time within acceptable limits, IPM utilizes model plants to represent aggregations of actual individual generating units. The aggregation algorithm groups units with similar characteristics into model plants with a combined capacity and weighted-average characteristics that are representative of all the units comprising the model plant. Model plants are defined to maximize the accuracy of the model's cost and emissions estimates by capturing variations in key features of those units that are critical in the base case and anticipated policy case runs. For EPA Base Case 2000, IPM employed an aggregation algorithm which allowed 12,283 actual existing electric generating units to be represented by 1,385 model plants. Section 4.2.6 describes the aggregation algorithm used in the EPA Base Case 2000.

Retrofit, Repowering, and Retirement Options: IPM also utilizes model plants to represent the retrofit and repowering options that are available to existing units and the retirement options that are available to both existing and potential (new) units. For example, EPA Base Case 2000 allows existing model plants to retrofit with pollution control equipment, repower, retire early and, in the case of nuclear units, re-license. (See Chapters 5 and 6 for a detailed discussion of the options that are included in the EPA Base Case 2000.)

The options available to each existing and potential (new) model plant are pre-defined at set-up. The retrofit, repowering, and retirement options are themselves represented in IPM by model plants, which, if actuated in the course of a model run, take on all or a portion of the capacity and generation initially assigned to an existing or potential model plant. That is, in setting up IPM, parent-child-grandchild relationships are pre-defined between each existing and potential model plant (parent) and the specific retrofit, repowering and retirement model plants (children and grandchildren) that may replace the parent model plant during the course of a model run. The "child" and "grandchild" model-plants are inactive in IPM unless an existing model plant finds it economical to engage one of the options provided, i.e. retrofit with pollution control, repower, retire early or re-license.

Theoretically, there are no limits on the number of "child," "grandchild," and even "great-grandchild" model plants (i.e., retrofit, repowering, and retirement options) that can be associated with each existing model plant. However, model size and computational considerations dictate that the number of successive retrofits be limited. In EPA Base Case 2000, a maximum of two stages of retrofit options are provided (child and grandchild, but not great-grandchild). For example, an existing model plant may be retrofit with a scrubber in one model run year (stage 1) and with an SCR in the same or subsequent run year (stage 2). However, if it exercises this succession of retrofit options, no further retrofit, repowering, or retirement options are possible beyond the second stage.

Potential (New) Units: IPM also uses model plants to represent new generation capacity that may be built during a model run. All the model plants representing new capacity are pre-defined at set-up, differentiated by type of technology, regional location, and years available. For example, in EPA Base Case 2000, 887 model plants are predefined to represent six types of new fossil and nuclear generating capacity and 7 types of new renewable generating capacity. For a particular technology (e.g., wind generation), one of the 26 regions in EPA Base Case 2000 may be assigned anywhere from 0 to 18 model plants depending on the characteristics of the technology and the region. When it is economically advantageous to do so, IPM "builds" one or more of these predefined model plants by raising its generation capacity from zero during the course of a model run. In determining whether it is economically advantageous to "build" new plants, IPM takes into account cost differentials between technologies, expected technology cost improvements (by differentiating costs based on a plant's vintage, i.e., build year) and regional variations in capital costs that are expected to occur over time.

Since EPA Base Case 2000 results are presented at the model plant level, EPA has developed a post-processor "parsing" tool designed to translate results at the model plant level into generating unit-specific results. The parsing tool produces unit-specific emissions, fuel use, pollution control retrofit and capacity projections based on model plant results.

2.3.2 Model Run Years

Another important structural feature of IPM is the use of model run years to represent the full planning horizon being modeled. Mapping each year in the planning horizon into a representative model run year enables IPM to perform multiple year analyses while keeping the model size manageable. Although IPM reports results only for model run years, it takes into account the costs in all years in the planning horizon. (See Section 2.3.3 below for further details.) To avoid boundary distortions, models like IPM typically include a final model run year that is not included in the analysis of results. This technique reduces the likelihood that later year results will be skewed due to the modeling artifact of having to specify an end point in the planning horizon, whereas, in reality, economic decisions are likely to persist beyond that end point. While the planning horizon for EPA Base Case 2000 covers the period 2005 – 2030, only four of the model's five runs years (2005, 2010, 2015, and 2020), spanning the period 2005-2022, are used in analyses. To avoid boundary distortions, the final run year, covering the period 2023– 2030, is not considered in analyses of run results. Section 6.1 contains further discussion of the run years and mapping scheme assumptions used in the EPA Base Case 2000.

2.3.3 Cost Accounting

As noted earlier in the chapter, IPM is a dynamic linear programming model that finds the least cost investment and electricity dispatch strategy for meeting electric demand subject to resource availability and other operating and environmental constraints. The cost components that IPM takes into account in deriving an optimal solution include the costs of investing in new supply options, the cost of installing and operating pollution control technology, fuel costs and the operation and maintenance costs associated with unit operations.

Several cost accounting assumptions are built into IPM's objective function that ensure a technically sound and unbiased treatment of the cost of all investment options offered in the model. These features include:

- All costs in IPM's single multi-year objective function are discounted to a base year. Since the model solves for all run years simultaneously, discounting to a common base year ensures that IPM properly captures complex inter-temporal cost relationships.

- Capital costs in IPM's objective function are represented as the net present value of levelized stream of annual capital outlays, not as a one-time total investment cost. The payment period used in calculating the levelized annual outlays never extends beyond the model's planning horizon: it is either the book life of the investment or the years remaining in the planning horizon, whichever is shorter. This treatment of capital costs ensures both realism and consistency in accounting for the full cost of each of the investment options in the model.

- The cost components appearing in IPM's objective function represent the composite cost over all years in the planning horizon rather than just the cost in the individual model run years. This permits the model to capture more accurately the escalation of the cost components over time.

2.3.4 Modeling Wholesale Electric Markets

Another important methodological feature worth noting about IPM is that it is designed to depict production activity in deregulated wholesale electric markets, not in retail markets. The model captures transmission costs and losses between IPM model regions. It is not designed to capture retail distribution costs. However, the model implicitly includes distribution losses since net energy for load,[2] rather than delivered sales,[3] is used to represent electric demand in the model. Additionally, the production costs calculated by IPM are the wholesale production costs. In reporting costs, the model does not include embedded costs, such as carrying charges of existing units, that may be part of the retail cost.

2.3.5 Load Duration Curve (LDC)

Another notable methodological feature of IPM is its use of region-specific, seasonal load duration curves (LDCs) to capture the hourly profile of future electric demand. Unlike a chronological electric load curve,

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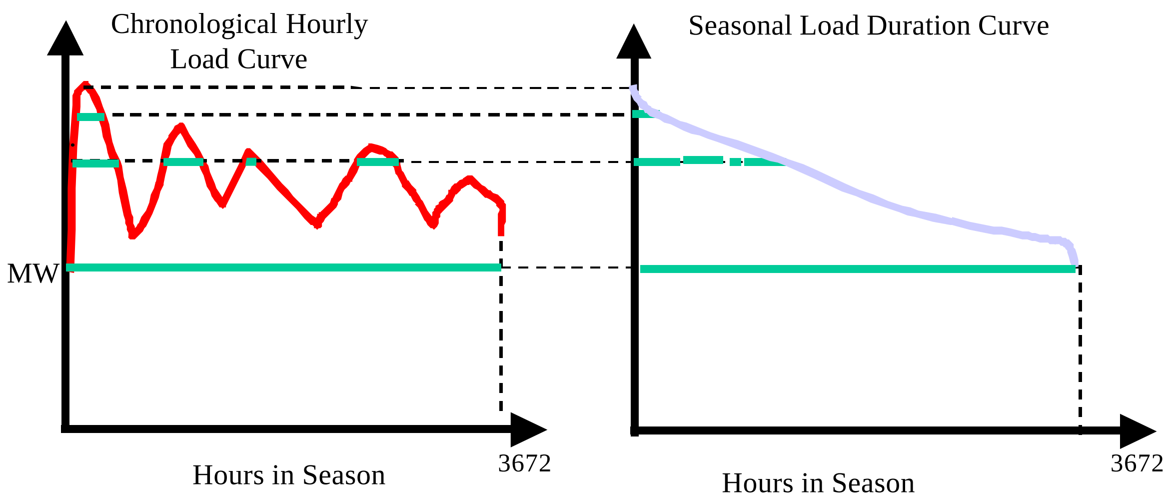
[2]Net energy for load is the electrical energy requirements of an electrical system, defined as system net generation, plus energy received from others, less energy delivered to others through interchange. It includes distribution losses.

[3]Delivered sales is the electrical energy delivered under a sales agreement. It does not include distribution losses.

which is simply an hourly ordering of electric demand, an LDC is an ordering of electric demand from the highest hourly load to the lowest hourly load over the full duration of the period being depicted. IPM uses the annual chronological load curves to develop seasonal LDCs. IPM allows users to include any number of customized seasonal definitions. A season can be a single month or several months. For example, EPA Base Case 2000 contains two seasons: summer (May – September) and winter (October – April). Figure 2.1 below presents side-by-side graphs of a hypothetical chronological hourly load curve and a corresponding load duration curve for a season consisting of 3,672 hours.

Figure 2.1: Hypothetical Chronological Hourly Load Curve and Seasonal Load Duration Curve



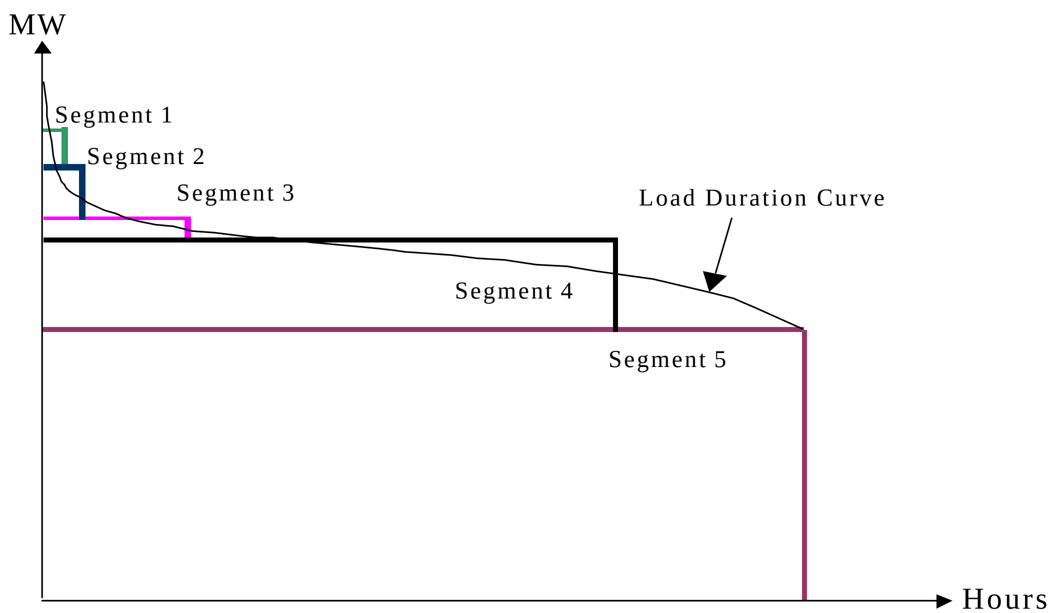
In EPA Base Case 2000 the process that culminated in seasonal LDCs for each IPM region began with the selection of a historical chronological load curve that was most representative of the historically average weather (termed "weather normal") in each NERC region. The historical data was obtained from Federal Energy Regulatory Commission (FERC) Form 714. For example, 1995 was found to yield weather normal data for the WSCC NERC region, whereas 1996 was found to offer weather normal data for the ERCOT region.

Based on seasons defined as described above, the annual chronological data was disaggregated into seasonal chronological load curves. The seasonal chronological data was then sorted from highest to lowest load to create seasonalized historical load duration curves. National electric demand growth assumptions and NERC's forecasts of peak and energy demand in each region were used to derive future seasonal load duration curves for each IPM run year in each IPM region from the historical data. The results of this process were individualized seasonal LDCs that capture the unique hourly electric demand profile of each region. The LDCs change over time to reflect projected future variations in electricity consumption patterns.

Within the Integrated Planning Model, LDCs are represented by a discrete number of horizontal segments, or strips, as illustrated in Figure 2.2. The top segment generally contains less than one percent of the hours in the period (i.e., "season"). The bottom segment includes 100 percent of the hours and has a load level equal to the minimum system load. The number of segments is flexible and is a user input. A greater number of segments provides a more detailed depiction of customer loads to the model's dispatch algorithm, but also increases the computational time of the model. As illustrated in Figure 2.2, the EPA Base Case 2000 uses five segments.

Use of seasonal LDCs rather than annual LDCs allows IPM to capture seasonal differences in the level and patterns of customer demand for electricity. For example, air conditioner cycling only impacts customer demand patterns during the summer season. The use of seasonal LDCs also allows IPM to capture seasonal variations in the generation resources available to respond to the customer demand depicted in an LDC. For example, power exchanges between utility systems may be seasonal in nature. Some air regulations affecting power plants are also seasonal in nature. This can impact the type of generating resources that are dispatched during a particular season. Further, because of maintenance scheduling for individual generating units, the capacity and utilization for these supply resources also vary between seasons.

Figure 2.2: Stylized Depiction of the Five Load Segments Used in EPA Base Case 2000

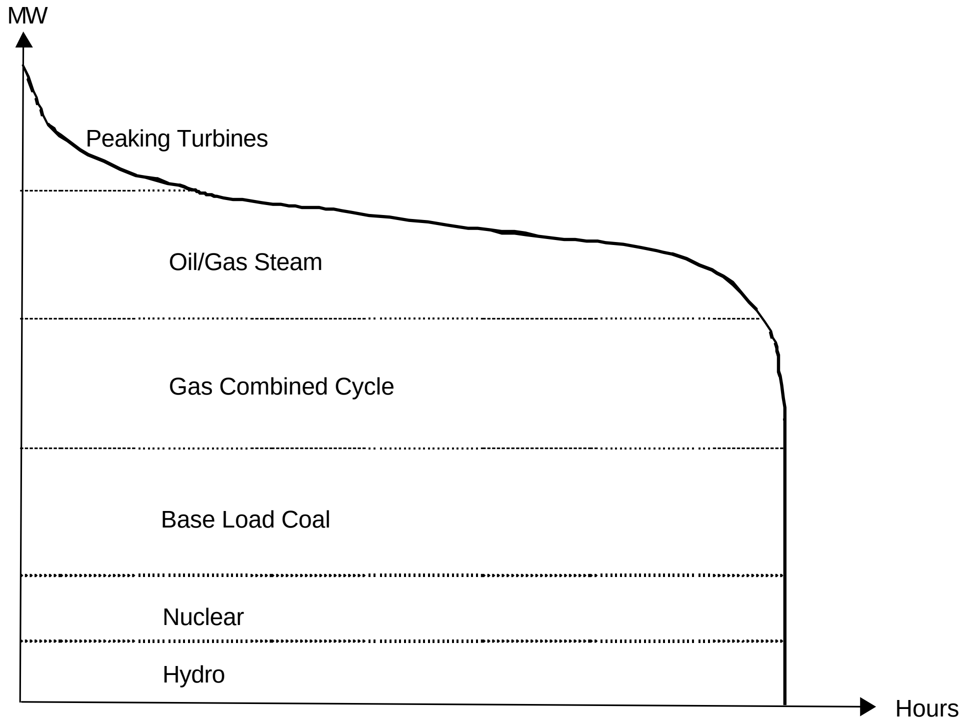


2.3.6 Dispatch Modeling

In IPM, the dispatching of electricity is based on the variable cost of generation. In the absence of any operating constraints, units with the lowest variable cost generate first. The marginal generating unit, i.e., the power plant that generates the last unit of electricity, sets the energy price. Physical operating constraints also influence the dispatch order. For example, IPM uses turndown constraints to prevent base load units from cycling, i.e., switching on and off. Turndown constraints often override the dispatch order that would result based purely on the variable cost of generation. Using variable costs in combination with turndown constraints enables IPM to dispatch generation resources in a technically realistic fashion.

Figure 2.3 below depicts a highly stylized dispatch order based on the variable cost of generation of the resource options included in the EPA Base Case 2000. In Figure 2.3 a hypothetical load duration curve is subdivided according to the type of generation resource that responds to the load requirements represented in the curve. Notice that the generation resources with the lowest operating cost (i.e, hydro and nuclear) respond first to the demand represented in the LDC and so are at the bottom of "dispatch stack." They are dispatched for the maximum possible number of hours represented in the LDC. Generation resources with the highest operating cost (i.e., peaking turbines) are at the top of the "dispatch stack," since they are dispatched last and for the minimum possible number of hours.

Figure 2.3. Stylized Dispatch Order



2.3.7 Reliability Modeling

Another methodological feature of IPM is its modeling of reliability through reserve margin requirements, which specify a percent over the peak demand that the electric system must maintain. IPM includes separate reserve margin requirements for each model region and run year. Section 3.6 contains a discussion of the reserve margin assumptions in EPA Base Case 2000.

2.3.8 Fuel Modeling

Another key methodological feature of IPM is its capability to flexibly model the full range of fuels used for electric power generation. The price, supply, and (if applicable) quality of each fuel included in the model are defined during model set-up. Fuel price and supply are specified through either a supply curve or an exogenous price stream, both of which may vary over time. When a fuel supply curve is included, the model endogenously determines the price for that fuel by balancing the supply and demand. IPM uses the fuel quality information (e.g., the sulfur or mercury content of different types of coal from different supply regions) to determine the emissions resulting from the combustion of that fuel.

The EPA Base Case 2000 includes coal, gas, oil, nuclear fuel, and biomass as fuels for electric generation. The specific base case assumptions for these fuels are examined in Chapter 8.

2.3.9 Transmission Modeling

IPM includes a detailed representation of existing transmission capabilities between model regions along with options for building new transmission lines. The maximum transmission capabilities between regions are specified in IPM's transmission constraints. Additions to transmission lines are represented by decision variables defined for each eligible link and model run year. In IPM's objective function, the decision variables representing transmission additions are multiplied by new transmission line investment cost and capital charge rates to obtain the capital cost associated with the transmission addition. Due to extensive unresolved policy issues and long-term uncertainty surrounding the building of new transmission lines in the U.S., EPA Base Case 2000 does not exercise IPM's capability to model the building of new transmission lines. The specific transmission assumptions in EPA Base Case 2000 are described in section 3.3.

2.3.10 Perfect Competition and Perfect Foresight

Two key methodological features of IPM are its assumptions of perfect competition and perfect foresight. The former means that IPM models production activity in wholesale electric markets on the premise that these markets subscribe to all assumptions of perfect competition. The model does not explicitly capture any market imperfections such as market power, transaction costs, informational asymmetry or uncertainty. However, if desired, appropriately designed sensitivity analyses or redefined model parameters can be used to gauge the impact of market imperfections on the wholesale electric markets. Since the retail electric market is not modeled in IPM, there are no assumptions about the extent or timing of retail deregulation.

IPM's assumption of perfect foresight implies that economic agents know precisely the nature and timing of the constraints that will be imposed in future years. For example, under IPM there is complete foreknowledge of the levels, timing, and regulatory design of emission limits that will be imposed over the entire modeling time horizon. In making decisions, agents optimize based on this foreknowledge. However, by performing an iterative series of runs, in which new emission limits are successively added in subsequent model run years, imperfect foresight can be incorporated in IPM's projections.

2.3.11 Air Regulatory Modeling

One of the most notable features of IPM is its detailed and flexible modeling of air regulations. Treatment of air regulations is endogenous in IPM. That is, by providing a comprehensive representation of compliance options, IPM enables environmental decisions to be made within the model based on least cost considerations, rather than exogenously imposing environmental choices on model results. For example, unlike other models that enter allowance prices as an exogenous input during model set-up, IPM obtains allowance prices as an output of the endogenous optimization process of finding the least cost compliance options in response to air regulations. (In linear programming terminology, they are the "shadow prices" of the respective emission constraints — a standard output produced in solving a linear programming problem.) IPM can capture a wide variety of regulatory program designs including cap-and-trade, command-and-control and renewable portfolio standards. IPM's representation of cap-and-trade programs can include allowance banking, trading, borrowing, progressive flow controls or emission taxes. Air regulations can be tailored to specific geographical regions and can be restricted to specific seasons. Many of these regulatory modeling capabilities are exploited in EPA Base Case 2000 .

2.4 Hardware and Programming Features

IPM produces executable files in standard MPS linear programming format[4]. IPM runs on most PC-platforms. Its hardware requirements are highly dependent on the size of a particular model run. For example, EPA Base Case 2000 is run on a PC platform with dual 1.7 GHz Pentium IV processors and 4 GB of RAM using Dash Optimization's Xpress-MP software as the linear programming solver.

Two data processors -- a front-end and the Parsing Tool -- support the model. The front-end creates the necessary input files used in IPM, while the Parsing Tool maps IPM model-plant level outputs to individual generating units (see section 2.3.1).

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[4]Mathematical Programming System (MPS) format is the industry standard format used in linear and quadratic programming.

Before it can be run, the model requires an extensive set of input parameters. These are discussed in Section 2.4.1 below. Results of model runs are presented in a series of detailed reports. These are described in Section 2.4.2 below.

2.4.1 Data Parameters for Model Inputs

IPM requires input parameters that characterize the US electric system, economic outlook, fuel supply and air regulatory framework. Chapters 3-8 contain detailed discussions of the values assigned to these parameters in EPA Base Case 2000. This section simply lists the key input parameters required by IPM:

- **Electric System**
  - *Existing Utility Generating Resources*
    - Plant Capacities
    - Heat Rates
    - Maintenance Schedule
    - Forced Outage Rate
    - Minimum Generation Requirements (Turn Down Constraint)
    - Fuels Used
    - Fixed and Variable O&M Costs
    - Emissions Limits or Emission Rates for NO_x, SO_2, CO_2, Mercury
    - Existing Pollution Control Equipment and Retrofit Options
    - Output Profile for Non-Dispatchable Resources
  - *New Generating Resources*
    - Cost and Operating Characteristics
    - Performance Characteristics
    - Limitations on Availability
  - *Other System Requirements*
    - Inter-regional Transmission Capabilities
    - Reserve Margin Requirements for Reliability
    - Area Protection
    - System Specific Generation Requirements
    - Regional Specification

- **Economic Outlook**
  - *Electric Demand*
    - Firm Regional Electric Demand
    - Load Curves
  - *Financial Outlook*
    - Capital Charge Rate
    - Discount Rate

- **Fuel Supply**
  - *Fuel Supply Curves for Coal, Natural Gas, and Biomass*
  - *Fuel Price*
  - *Fuel Quality*
  - *Transportation Costs for Coal, Natural Gas, and Biomass*

- **Air Regulatory Outlook**
  - *Air Regulations for NO_x, SO_2, CO_2, Mercury*
  - *Other Air Regulations*

2.4.2 Model Outputs

IPM produces a variety of output reports. These range from extremely detailed reports, which describe the results for each model plant and run year, to summary reports, which present results for regional and national aggregates. Individual topic areas can be included or excluded at the user's discretion. Since the entire model solution is stored, IPM can generate additional detailed reports from the stored solution as needed. Standard IPM reports cover the following topics:

- Generation
- Capacity mix (by plant type and presence or absence of emission controls)
- Capacity additions and retirements
- Capacity prices
- Wholesale electricity prices
- Power production costs (capital VOM, FOM and fuel costs)
- Fuel consumption
- Fuel supply and demand
- Fuel prices for coal, natural gas, and biomass
- Emissions (NO_x, SO_2, CO_2, and Hg)
- Allowance prices